Joint Response of the Alliance for Retail Energy Markets, Direct Access Customer Coalition and Shell Energy North America (US) L.P. to the Optional Homework Assignment A.14-05-024

The following is the joint response of the Alliance for Retail Energy Markets, the Direct Access Customer Coalition and Shell Energy North America (US) L.P. (jointly, the "DA Parties") to the Optional Homework Assignment circulated by William Maguire of Energy Division Staff on January 22, 2016.

As a preliminary matter, an important issue that must be addressed by the Commission is how the homework responses from various parties and the discussion at the March 8 workshop are to be incorporated into the record of A.14-05-024. One alternative would be the preparation of a formal workshop report, to be followed by opening and reply comments by all interested parties. The report could be prepared by Energy Division or could be a joint effort by interested parties. Regardless of the approach that is adopted it is important to ensure a formal record is created on the PCIA issue and that this topic is added to the agenda for the workshop. We look forward to discussing these issues with all parties.

1. Please indicate your understanding of how the PCIA is calculated, identifying, in as much details as possible, each input to that calculation.

A. Calculation of the Market Price Benchmark

The Market Price Benchmark (MPB) is calculated for each vintage, based on the following:

1. **A Forwards-Based Market Price for Energy**. The Forwards-Based Market Price is an average of the *Platts-ICE Forward Curve-Electricity ("Platts")* published market indices for a one-year strip of peak and off-peak power prices for the coming calendar year for NP15 and SP15, published over the period October 1 through October 31 of the year prior to that being considered. For example, the 2016 benchmark is based on an average of *Platts* calendar year 2016 power forward indices published for the period from

October 1 through October 31, 2015. This average is calculated separately for NP15 and for SP15. PG&E's benchmarks are based on NP15 prices; SCE and SDG&E's benchmarks are based on SP15 prices. The Forwards-Based Market Price is equal to the weighted average of the SP15 or NP15 peak and off-peak forward prices, and does not vary by Vintage.

2. **Capacity Adder**. The sum of the Net Qualifying Capacity in each Vintage's portfolio is multiplied by "California Energy Commission's estimates of the going forward costs of a combustion turbine" and divided by the annual volume of that vintage to obtain each Vintage-specific capacity adder on a dollar-per-MWh basis. The Energy Commission cost estimates are provided in the "Cost of Generation Report," which is updated roughly every 3-5 years.
3. **Renewable Premium**. The Renewable Premium is calculated as the sum of (i) the "IOU RPS Premium" times 0.68, and (ii) the "DOE REC value" times 0.32. The IOU RPS Premium equals the weighted average cost of the IOUs' renewable power from those RPS resources with delivery start dates in either the year prior to that being considered or in the year being considered, minus the Forwards-based Market benchmark described in Step 1 above. For example, the 2016 benchmark is based on the average cost of the IOUs' RPS power from contracts beginning delivery in 2015 and 2016. The "DOE REC value" is the average of the voluntary retail rate premiums for renewable energy in the Western U.S. as reported in a U.S. Department of Energy annual survey. The renewable premium is the same for all Vintages.
4. **Renewable Adder.** For each Vintage, the Renewable Premium is multiplied by the RPS fraction of each Vintage's Portfolio to arrive at the Renewable Adder. For example, if 22% of the energy in a Vintage's Portfolio is generated by RPS renewables, then the Renewable Premium would be multiplied by 0.22 to arrive at the Renewable Adder.

5. **Market Price Benchmark.** For each Vintage, the Forwards-Based Market Price, Capacity Adder and Renewable Adder are summed and multiplied by a line loss factor to arrive at the final Market Price Benchmark, which represents the estimated market price at the customers' meter.

B. Calculation of the Indifference Amount

1. Each IOU runs its least cost economic dispatch model serving its bundled load, noting the costs and output of each eligible resource. Short-term power purchases for terms of less than one year are not considered eligible resources, and neither are non-RPS contracts beginning in Year 11 of contract deliveries.
2. Each eligible resource is assigned to specific Vintages corresponding to when the IOU committed to taking that resource (i.e., when the IOU executed the contract or began construction of the new resource). For example, a contract executed in 2015 is assigned to Vintage 2015, Vintage 2016, and all subsequent Vintages until that contract is no longer PCIA-eligible (i.e., the contract expires or, if it is a non-RPS contracts, it exceeds the 10-year cap on PCIA eligibility).
3. Total Portfolio Costs and volumes for each Vintage are calculated by summing the resource volume (MWhs) and costs for all resources included in that Vintage.
4. The volume for each Vintage's Total Portfolio is scaled downward to reflect line losses and thus equal the MWhs seen at customers' meters.
5. The volume of each Vintage's Total Portfolio (MWhs) is multiplied by the Market Price Benchmark, equaling the "market value" of that Vintage's portfolio.
6. The market value of each Vintage's portfolio is subtracted from the Total Portfolio Cost of each corresponding Vintage to arrive at the "above market costs" or Indifference Amount.

C. Calculation of the PCIA Rate

The PCIA Rate is calculated for each Vintage and rate schedule by applying the top 50 hours cost allocators to the Indifference Amount and subtracting the CTC to arrive at each individual rate schedule's PCIA. If the PCIA is negative, the PCIA rate is set to zero and the negative amount is tracked and credited against positive PCIA amounts in future years.

2. Do you believe the current PCIA methodology should be changed? If so, how and why? Please be as specific as possible.

The DA Parties offer the following three proposals for changes to the current PCIA methodology.

a. **Alternative PCIA payment.** The DA Parties believe that there should be an option for non-continuous DA customers to pay a lump sum amount equal to the present value of future expected PCIA obligations and thereafter be exempted from paying the tariffed PCIA. This would be analogous to payments by a publicly owned utility to the IOUs for projected PCIA and other non-bypassable rate obligations that new and transferred municipal departing load customers would have otherwise paid. This ability is authorized in (for example) SCE's Schedule TMDL (Transferred Municipal Departing Load), which states in Special Condition 3:

> Bilateral agreements between SCE and the respective POUs or POU customer can be used as an alternative to the process set forth in this Schedule. If such an alternative mechanism or arrangement is not agreed to, SCE will utilize the following procedures [to charge customers the TMDL fees.

Analogous language appears in the schedule applicable to new municipal departing load (SCE Schedule NMDL). This condition has been used by numerous municipal utilities, including ones serving City of Hercules, City of Industry, City of Rancho Cucamonga, and Moreno Valley.

The precise amount of the lump-sum PCIA (LSPCIA) would be based on the projected net present value of future PCIA obligations, using the indifference and benchmark formulas in place at the time and mutually acceptable inputs into those formulas. The DA Parties believe that a separate utility tariff and a new DA/CCA Rule may be the best way for the details of the LSPCIA calculation to be specified. The LSPCIA funds received by the IOU would be included as a credit to the Energy Resource Recovery Account (ERRA). The DA Parties expect that it will be necessary for the funds to be held in a balancing account and credited to the ERRA over a selected number of years, so as to avoid: (a) excessively skewing the bundled rate; (b) sending improper price signals to direct access customers or CCAs; and (c) bundled rate volatility.

The DA Parties acknowledge that the LSPCIA payment will be based on market prices and conditions at the time the calculation is made, and therefore over time, the stranded costs associated with portfolio may be different than the present value calculation paid by the DA customer. However, if the estimate is done in good faith and agreed to by both the DA customer and the IOU, the risk that the LSPCIA payment overstates future PCIA obligations (detrimental to the DA customer but beneficial to bundled customers) should balance the risk that it understates the future obligation (beneficial to the DA customer but detrimental to bundled customers). As such, the DA Parties believe that the requirement of bundled customer indifference would still be met.

b. **A "sunset" on PCIA obligations.** For each PCIA vintage, the PCIA would discontinue for that vintage of DA customers after a certain number of years, whether that be administratively set, or when load growth equals the amount of load lost by the DA departed loads in that vintage, or some other criteria. Thus, for existing vintages, the years to the sunset date (relative to now) would vary based on the time the vintage has been in place, with the oldest vintages having the shortest time to the sunset date. A sunset provision provides more balance between the obligations of departing customers and maintaining bundled customer indifference in that it provides continued substantive protections to bundled customers while at the same time creating an incentive for more proactive procurement planning by the utilities to manage the impact of the sunsetting PCIAs.

c. **Fixing DA PCIA vintages.** Per Decision 12-01-033, the IOUs' bundled customer planning forecasts are to reflect the maximum allowable phase-in of DA sales permitted under Senate Bill ("SB") 695.[1] In addition, D.14-02-040 required the utilities to forecast "reasonable levels" of DA and CCA departing load over the 10-year bundled forecast period.[2] As such, and especially when DA load is capped and the cap is full, there should be no new DA "vintages" past the year in which the DA cap was filled (2012). Under this approach, if new load begins DA service because room opens up under the cap, there is no need for a new vintage to be created for that customer because there has been no net increase in the amount of the load that has departed. Moreover, if the DA cap is increased, the utility is obligated to exclude that new DA load from its bundled procurement plans, so no new vintages would be established after the date of that exclusion. The Commission committed in D.15-10-031 to consider this proposal in a future proceeding and this re-examination of PCIA rules is the proper forum in which to address this proposal.[3]

[1] D.12-01-033, Finding of Fact 13.
[2] D.14-02040, Ordering Paragraph 1.
[3] D.15-10-031, pp. 47-48.

3. **How should the CPUC address the potential departure from bundled service of a very large load, such as the City of San Diego or County of Los Angeles? Would transferring contractual responsibility from an IOU to a CCA be an option?**

The DA Parties have no specific recommendations on this matter at this time, except to note that any adjustments made to the PCIA or utility planning process to accommodate "very large" (however that is to be defined) CCA load departure, must not harm DA customers by raising the PCIA they otherwise would have paid or in any other way. Moreover, to the extent this question is suggesting that a "large departing load" could have the option of taking assignment of specific utility contracts, that idea might have merit, but practically speaking may be difficult to implement since the PCIA calculation is based on a portfolio calculation while assignment of specific contracts would reflect only one piece of the portfolio.

The DA Parties also note that the utility systems successfully accommodated the large load departures that occurred when the DA market was opened in 1998.[4] Both the rules and utility systems for accommodating departing load have become significantly more sophisticated since then, which suggests that a large CCA departure could be handled successfully.

4. **Should Direct Access (DA) customers and Community Choice Aggregator (CCA) customers be treated differently vis-à-vis the PCIA? If so, why and how?**

The PCIA should be calculated in the same way for CCA customers as it is for DA customers. Nonetheless, there may be CCA- or DA-specific issues that could warrant differing treatment, such as the assignment of PCIA vintages issue raised by MCE in the last two PG&E ERRA proceedings with respect to customer relocations within a CCA's territories.

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[4] The Direct Access Service Reports ("DASR's) posted on the Commission's web site show that 13,305 GWh or 8.2% of the IOUs' load departed in 3 months and a total of 21,981GWh or 13.2% of the IOU's load departed within 1 year of the market opening in April 1998.

5. **Can transparency regarding the calculation of the PCIA be increased while protecting valid interests in keeping certain information confidential?**

The DA Parties favor additional transparency in the PCIA calculation. For instance, there should greater information from and access to precisely which contracts are included in each vintage, including the contractual counterparty, product (resource adequacy, energy, renewable, storage, etc.), volume and contract duration. The DA Parties do not believe that this type of information is considered confidential, and notes that this suggestion does not include specific contractual pricing information, as that information is considered confidential.